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Introduction

Crude oil is the most important natural source of energy in all industrialized countries, as modern civilization and its remarkable accomplishments would not exist without oil. What makes it so important in our everyday lives is its broad variety of uses. Apart from fuelling cars, airplanes etc., and its components can be used to manufacture many types of chemical products such as plastics, medicine, detergents and many other things. Even though oil is not an unlimited source of energy, the proven reserves indicate that crude oil can supply the planet's energy demands for many decades to come. According to OPEC, the total proven reserves of all oil producing countries are 1.3 trillion barrels of oil. To realize the magnitude of the above figures, it is estimated that we have already consumed about 1 trillion barrels. Global demand on energy is continuously growing and oil is produced in larger quantities than it used to some decades ago.

Any production well is drilled and completed to move the oil or gas from its original location in the reservoir to the stock tank or sales line. Movement or transport of these fluids requires energy to overcome friction losses in the systemand to lift the products to the surface. The fluid must travel through the reservoir and the piping system and ultimately flow into a separator for gas-liquid separation. The production system can be relatively simple or can include many components in which energy or pressure losses occur.

The pressure drop in the total systemat any time will be the initial fluid pressure minus the fluid pressure. This pressure drop is the sum of all the pressure drops occurring in all the components of the system. Since the pressure drop through any components varies with producing rate, the producing rate will be controlled by the components selected. The selection and the sizing of the individual component is very important, but because of the interaction among the components, a change in the pressure drop in one may change the pressure drop behaviour in all the others. This occurs because the flowing fluid is compressible, and, therefore, the pressure drop in a particular component depends not only on the flow rate through the component, but also on the average pressure that exists in the component.

The final design of a production systemcannot be separated into reservoir performance and piping system performance and handled independently. The amount of oil and gas flowing into the well from the reservoir depends on the pressure drop in piping systems, and the pressure drop in the piping systemdepends on the amount of fluid flowing through it. Therefore, the entire production systemmust be analysed as a unit.

The production rate or deliverability of a well can often be severely restricted by the performance of only one component in the system. If the effect of each component on the total system performance can be isolated. The systemperformance can be optimized in the most economical way. Past experience has shown that large amount of money have been wasted on stimulating the formation when the well's producing capacity was actually been restricted because the tubing or flow line was too small. Another example of errors in completion design is to install tubing that is too large. This often happens on wells that are expected to produce at high rates. This practice not only wastes money on oversized equipment, but also tubing that is too large can actually reduce the rate at which a well will flow. This can cause the well to load up with liquids and die, which necessitates the early installation of artificially lift equipment or compression.

However, continuous discovery of new fields in combination with the optimization of production on the existing ones has become more essential than ever. The concept of production optimization was not introduced from the beginning of the oil age. Ever since, the progress in technology has provided the tools to Petroleum Engineers to exploit the oilfields as efficiently as possible and maximize recovery factors.

Back in the late 1800s till the beginning of the 20th century, the analysis of a petroleum production system was yet unknown. When the first oil reservoirs started to suffer from severe depletion, the concept of production optimization became a necessity. Due to the uncertainty and large amount of risk behind exploration for new fields, the need to exhaust all possibilities within the existing reservoirs became urgent. Engineers in the oil industry seek production optimization in three domains. From the reservoir engineering point of view, software specialized in reservoir simulation was developed in order to reduce the uncertainty that lies in a reservoir and predict the flow of fluids in porous media and make production forecasts. Software using the principles of material balance were also introduced to simplify calculations. The second domain which was thoroughly studied is the fluid flow from the reservoir, through the tubing, down to the surface facilities, in other words the ability of the well to deliver fluids to the surface. The need to reduce pressure losses in the tubulars led the engineers to confront this challenge by studying the systemas a unit comprised by several interacting components.

The analysis of the well as system of components was introduced in mid 50s by Gilbert. The main objective of such analysis is to combine the characteristics of each component in order to estimate production rates and optimize the system's productivity.

Initial reservoir pressure is generally large enough to lift the reservoir fluids up to the surface. As production continues, the pressure becomes gradually lower and the liquid rates are deteriorated. For this reason, the principles of fluid flow in porous media and pipelines were thoroughly examined. As the produced fluids travel from the reservoir to the surface facilities, a significant amount of pressure is wasted due to a series of factors. The optimization of these factors, so that the lowest pressure drop possible in a well occurs, is the reason behind the development of systemanalysis or else Nodal Analysis. The main purpose of this analysis is the prediction of achievable fluid production rates from reservoirs with specified production string characteristics. ***The technique of this analysis is better known as "Nodal Analysis" While the production optimization methods are called ''artificial lift methods''.*** Therefore, the main goal behind this technique and optimization methods is to optimize the well so that the maximum possible flowrates which could be achieved by the reservoir would not be restricted due to the design of the well.

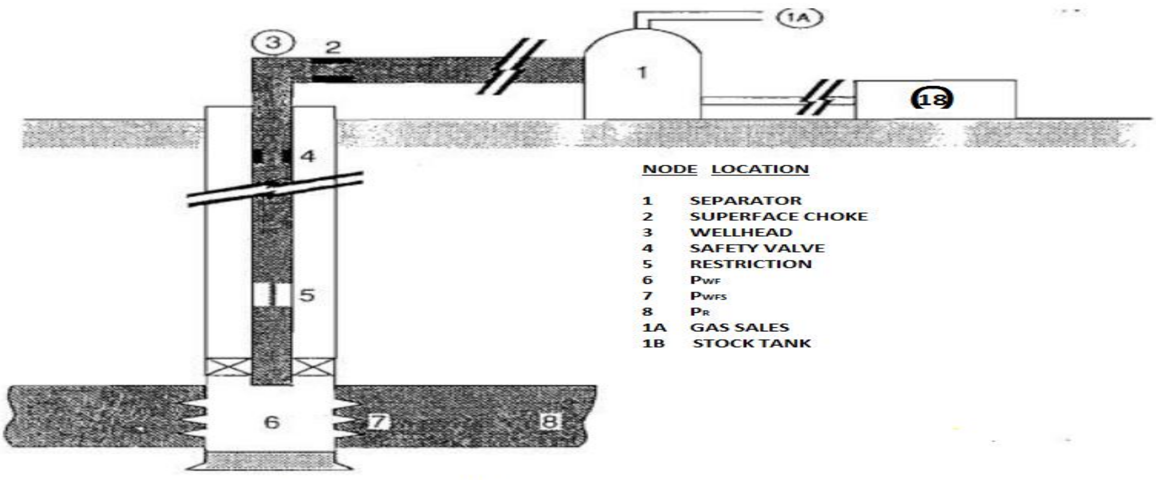
Nodal Analysis

Nodal Analysis has been applied for many years to analyse the performance of systems composed of interacting components. Electrical circuits, complex pipeline networks and centrifugal pumping systems are all analysed using this method. Its application to well producing systems was first proposed by Gilbert in 1954 and Mach, Proano, and Brown in 1979 further developed the concept.

The nodal analysis procedure consists of selecting a division point or node in the well and dividing the system at this point to optimize performance in the most economical manner. All of the components upstream of the node comprise the inflow section and all components downstream of the node comprise the outflow section. Each component behaviour in the system is directly related to flow rates and pressure drop. The flow rate through the whole system can be determined once the following requirements are satisfied:

1. **Flow into the node equals flow out of the node**, which means flow into the division point equals flow out of the division point.
2. **Only one pressure can exist at a node**. Which means the pressure at the division point is the same in both inflow and outflow sections of the system.

The various locations of the nodes are illustrated in the diagram below:



Locations of various nodes [1]

The pressures of both reservoir and separator or wellhead, are fixed. Since the node has a unique pressure, the following expressions can be used:

$$\overline{P_r} - \Delta P_{upstream} = P_{node}$$

$$P_{wh} + \Delta P_{downstream} = P_{node}$$

Where, Pr: the average reservoir pressure, psi

P_{wh}: the pressure at the wellhead, psi

$\Delta P_{upstream}$: the pressure loss due to upstream components, psi

$\Delta P_{downstream}$: the pressure loss due to upstream components, psi.

The pressure difference ($p_R - p_{wf}$) is called the *reservoir drawdown*. It is the primary force driving reservoir fluids into the wellbore. Generally, production rates increase with increasing drawdown. Note that the pressure drops both in the inflow and outflow depend on geometry, equipment etc. but most importantly on flowrate. If a sensitivity analysis on various liquid rates is made, the following diagram of node pressure versus flow rate can be derived (Fig. 2 below)

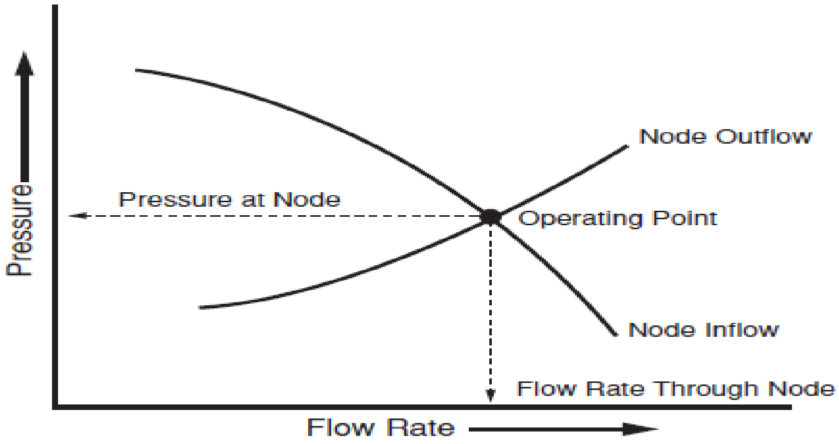


Figure 2: Inflow and outflow curve at a specific node (Courtesy of Heriot Watt University).

The point where these curves intersect is the operating point, i.e. the point which satisfies both constraining equations above. If these two curves do not intersect, then, no flow is established through the node, i.e. the well is dead. Imagine the well is dead! That is why we need well system analysis called Nodal analysis to prevent this kind of untold problems (loss). This can be achieved through **productivity index (PI)** which is denoted with the letter J, is the measure of the ability of the well to produce

$$J = \frac{q}{\overline{P_r} - P_{wf}} = \frac{2\pi kh}{\mu B_o} \frac{1}{\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S} \quad (Semisteady - state)$$

fluids.

Where q: liquid rate, stb/day.
J: productivity index, stb/day/psi.
Pr: average reservoir pressure (static pressure), psi.
Pwf : downhole flowing pressure, psi.
rw: wellbore radius, ft.
re: External drainage radius, ft
S: Skin factor, dimensionless.
h: Reservoir thickness, ft
µ: viscosity, cp.
Bo: formation volume factor, bbl/stb

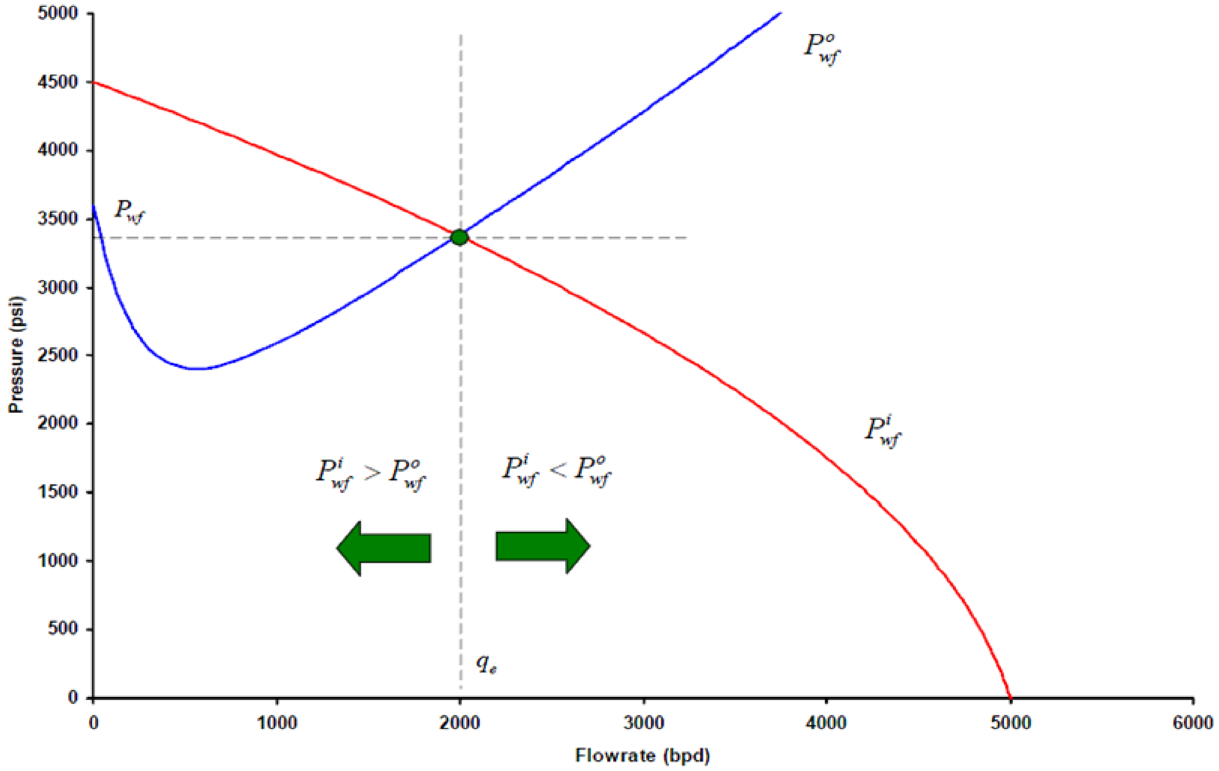
The productivity index is proved to be a very useful tool in Petroleum Engineering in order to predict future performance of wells. unexpected declines in the value of J can be concrete indications for a series of well issues such as damages due to workover, completion, mechanical problems etc.
Therefore, well system analysis (nodal analysis) is of crucial important, because it help us to optimized the well for better production, predict problems prior to their occurrence so as to take the necessary percussions that can optimized it and preserve its life-span.

Now what are the methods that engineers need in order to reinitiate or increase production? These production optimization methods are what we called ***artificial lift methods.***

Artificial lift

Production rate is the combined impact of reservoir delivery and wellbore plus flowline multiphase flow pressure change. When reservoir pressure declines or water fraction increases, the well's natural flow rate may be inadequate and artificial lift processes are implemented to increase or maintain rate.

The reservoir pressure, after a long period of production, will drop to such levels that the observed oil rates will not be economically viable. The worst case might be encountered when the pressure is insufficient to lift the liquids up to the surface and production will eventually seize. The need to maintain production for as long as possible, led the engineers among the industry to develop methods in order to reinitiate or increase production. Therefore, we can define Oil Artificial lift as a technique used to bring oil from the reservoir to the surface because of decreasing reservoir pressure.



IPR vs. OPR graph.

As illustrated in the diagram above, a well never actually attains its absolute flow potential, because in order for it to flow, Pwf must exceed the back pressure that the producing fluid exerts on the formation as it moves through the production system. This back pressure or *bottomhole pressure* has the following components-

- Hydrostatic pressure of the producing fluid column
- Friction pressure caused by fluid movement through the tubing, wellhead and surface equipment.
- Kinetic or potential losses due to diameter restrictions, pipe bends or elevation changes.

Artificial lift is therefore, a means of overcoming bottomhole pressure so that a well can produce at some desired rate, either by injecting gas into the producing fluid column to reduce its hydrostatic pressure, or using a downhole pump to provide additional lift pressure downhole.

We tend to associate artificial lift with mature, depleted fields, where reservoir average pressure (**Pavg**) has declined such that the reservoir can no longer produce under its natural energy. But these methods are also used in younger fields to increase production rates and improve project economics.

How artificial lift is achieved?

Generally this is achieved by the use of a mechanical device inside the well (known as pump or velocity string) or by decreasing the weight of the hydro-static column by injecting gas into the liquid some distance down the well.

When artificial lift is needed?

Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface.

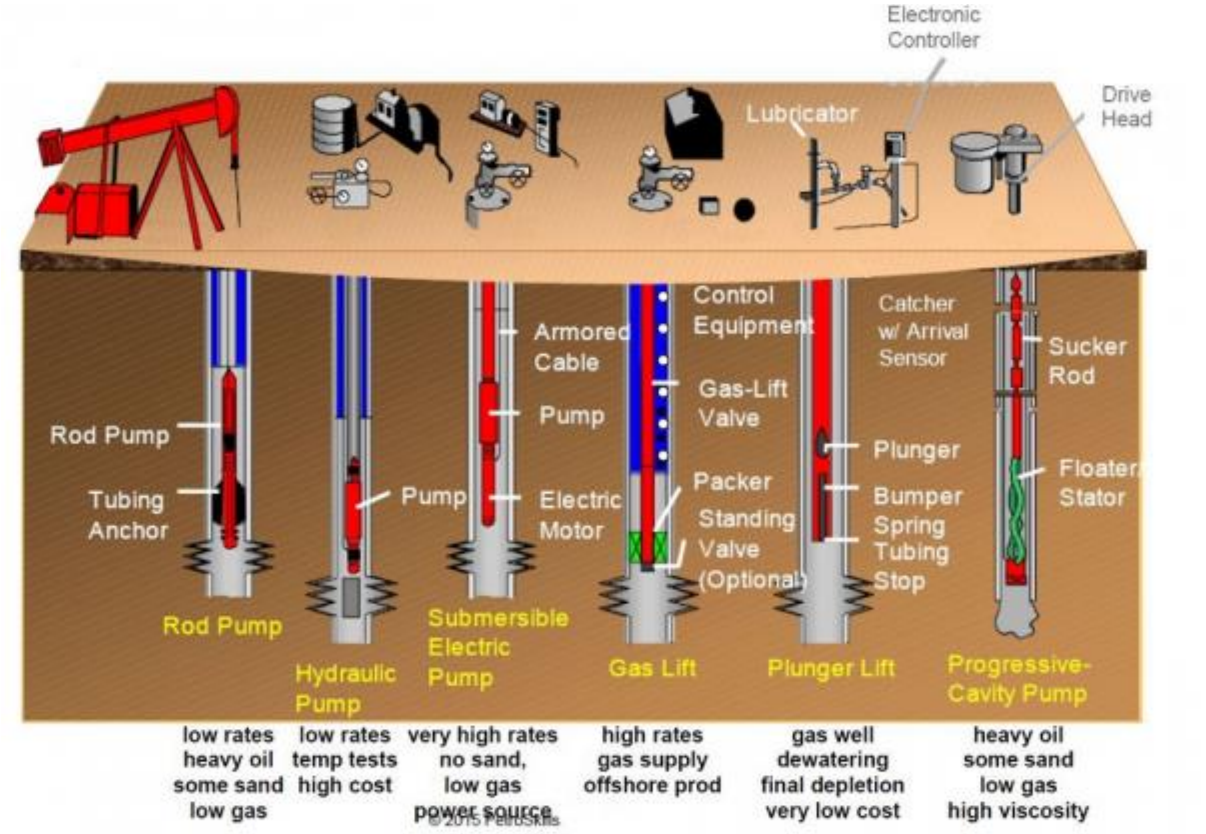
It also often used in naturally flowing wells to increase the flow rate above what would flow naturally.

Therefore, by carrying out artificial lift technique we aim to archive two goals:

1. Increasing the Gas-liquid ratio to maintain natural flow. This is when the oil well can still flow naturally so as to maintain its natural flow. Because people says ‘’Prevention is better than cure’’.

2. Transfer energy down-whole to pump the fluid and raise its pressure. This is mainly done in the case of wells that cannot push the oil up to the surface due to insufficient reservoir pressure and high density.

Methods of artificial lift: There are six methods of artificial lift, and they are categorised as follows-


Electronic Controller
Drive Head
Lubricator
Control Equipment
Catcher w/ Arrival Sensor
Armored Cable
Sucker Rod
Gas-Lift Valve
Pump
Rod Pump
Plunger
Floater Stator
Packer
Tubing Anchor
Pump
Electric Motor
Bumper Spring
Standing Valve (Optional)
Tubing Stop
Rod Pump
Submersible Electric Pump
Gas Lift
Plunger Lift
Progressive-Cavity Pump
Hydraulic Pump
low rates heavy oil some sand low gas
low rates temp tests high cost
very high rates no sand, low gas power source
high rates gas supply offshore prod
gas well dewatering final depletion very low cost
heavy oil some sand low gas high viscosity
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Six Primary Methods of Artificial Lift

1. Gas lift system

Gas lift technology increases oil production rate by injection of compressed gas in to the lower section of the tubing through the casing- tubing annulus. Upon entering the tubing, the compressed gas improves liquid flow in two ways:
(a) the energy of expansion pushes the oil to the surface and (b) the gas aerates the oil so that the effective density of the fluid is less, while the bottomhole pressure is reduced which leads to a greater pressure differential within the reservoir to attain a desired flow rate.
Therefore, the purpose here is to reduce the density of the flowing mixture of gas, oil, and water by increasing the gas-liquid ratio with gas injection into the tubing through a gas lift valve or orifice. Best lift occurs when injection is at a deep point in the wellbore. Gas lift is best applied when one or more of these characteristics are present: Reservoir fluid has a high gas content, well has a good reservoir productivity (PI), reservoir pressure can be maintained, fluid has entrained solids detrimental to pumps, and/or wellbore workover cost is high.

There are two main types of gas lift:

1. Continuous gas lift, where gas is injected in a constant, uninterrupted stream. It is therefore, a steady-state flow of the aerated fluid from the near bottom of the well to the surface which lowers the overall density of the fluid column and reduces the hydrostatic component of the flowing bottomhole pressure. This method is generally applied on wells with high productivity indices (PI).

2. Intermittent gas lift, which is designed for lower-productivity wells. In this type of gas lift installation, a volume of formation fluid accumulates inside the production tubing. A high-pressure "***slug***" of gas is then injected below the liquid, physically displacing it to the surface. As soon as the fluid is produced, gas injection is interrupted, and the cycle of liquid accumulation-gas injection-liquid production is repeated.

Therefore, if a well has a low reservoir pressure or a very low producing rate, it can be produced by this special form of gas lift system(intermittent flow). As its name implies, this system produces intermittently or irregularly and is designed to produce at the rate at which fluid enters the wellbore from the formation. In the intermittent flow system, fluid is allowed to accumulate and build up in the tubing at the bottom of the well. High pressure gas is injected into the liquid column on a cyclic or intermittent basis generating a gas bubble which expands pushing the liquid above it to the surface in a slug.

2. Pump-Assisted Lift or pumping methods

Pumping is a different process than gas lift. For pumping, the reservoir pressure is the driving energy to push fluid to the pump suction intake, not to the surface. Using the energy transferred downhole, the pump then raises the fluid pressure to drive it up to the wellhead, and into the surface facility. The pumping advantage is that reservoir pressure can decline much lower than that for natural flow or for a gas lift well.
Downhole pumps are used to increase pressure at the bottom of the tubing string by an amount sufficient to lift fluid to the surface. Therefore, the purpose is to transfer energy down-hole to pump the fluid and raise its pressure. These pumps fall into two basic categories: ***positive displacement pumps and dynamic displacement pumps.***

A positive displacement pump works by moving fluid from a suction chamber to a discharge chamber. This basic operating principle applies to reciprocating rod pumps, hydraulic piston pumps and progressive cavity pumps (PCPs).

A dynamic displacement pump works by causing fluid to move from inlet to outlet under its own momentum, as is the case with a centrifugal pump. Dynamic displacement pumps commonly used in artificial lift include electrical submersible pumps (ESPs) and hydraulic jet pumps. Let us now explain each of these pumping methods briefly:

2.1 Reciprocating rod pumps

Sucker rod pumps: use a rod string lifted by the surface beam pump to reciprocate the down-hole positive displacement pump. This activates the downhole, positive-displacement pump at the bottom of the well. Each time the rods and pumps are stroked, a volume of produced fluid is lifted through the sucker-rod tubing annulus and discharged at the surface.
Sucker Rod pumping system surface facilities consist of access to a power system and electric motor to drive the surface beam pump, or a gas engine driver connected to the beam pump. There are many pumping components but the primary ones are the beam pumping unit at the surface, sucker rod string, and downhole tubing pump or insert rod pump.

Beam pumping is the most common artificial lift method. It can be used for a wide range of production rates and operating conditions, and rod pump systems are relatively simple to operate and maintain. However, the volumetric efficiency (capacity) of a rod pump is low. Its initial installation may involve relatively high capital costs. Its application is very limited for deep, inclined and horizontal wells.

2.2 Hydraulic piston pumps

Hydraulic pump systems use a power fluid—usually light oil or water, depending on which is readily available —that is injected from the surface to operate or drive a downhole pump. Multiple wells can be produced using a single surface power fluid installation. The **reciprocating hydraulic pump** uses the high pressure injected “power” fluid, to operate or drive a downhole fluid “engine”, which in turn drives a piston to pump the reservoir fluid (formation fluid) pump and forces the reservoir fluids to the surface.

A *jet pump* is a type of hydraulic pump with no moving parts. Power fluid is injected into the pump body and into a small-diameter nozzle, where it becomes a low-pressure, high-velocity jet. Formation fluid mixes with the power fluid, and then passes into an expanding-diameter diffuser. This reduces the velocity of the fluid mixture, while causing its pressure to increase to a level that is sufficient to lift it to the surface. Thus, the hydraulic jet pumps convert the energy from the injected power fluid (water or oil) to pressure that lifts production fluids.

2.3 Progressive cavity pumps (PCPs)

The PCPs have been the most widely used pumping systems. The two key features that differentiate PCP systems from other forms of artificial lift are the downhole PC pumps and the associated surface drive systems. PCP is a screw pump with a single, helical rotor [21]. The downhole PC pump is a positive displacement pump that consists of two parts:

i. Helical steel “rotor”.
ii. “Stator” comprised of a steel tubular housing with a bonded elastomeric sleeve formed with a multiple internal helix matched suitably to the rotor configuration.
As the rotor turns, cavities between the rotor and stator move upward.

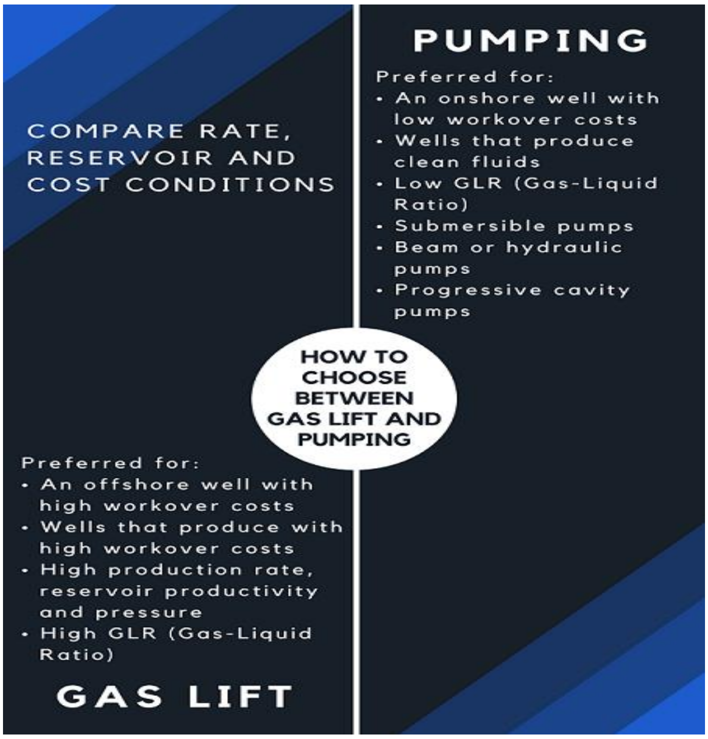
Progressive cavity pumps (PCPs) are commonly used for dewatering coal bed methane gas wells, for production and injection applications in water flood projects and for producing heavy or high-solids oil. They are versatile, generally very efficient, and excellent for handling fluids with high solids content. However, because of the torsional stresses placed on rod strings and temperature limitations on the stator elastomers, they are not used in deeper wells.

2.4 Electrical submersible pumps (ESPs).

An electric submersible pumping (ESP) assembly consists of a downhole centrifugal pump driven by a submersible electric motor, which is connected to a power source at the surface.

Among the Advantages of ***Electrical submersible pumps*** (ESPs) are: The pumps can be modified to lift corrosive fluids and sand, ESP systems can be used in high-angle and horizontal wells if placed in straight or vertical sections of the well. While among its disadvantages are: ESP pumps can be damaged from "gas lock". In wells producing high GOR fluids, a downhole gas separator must be installed. Another disadvantage is that ESP pumps have limited production ranges determined by the number and type of pump stages; changing production rates requires either a pump change or installation of a variable-speed surface drive. The tubing must be pulled for pump repairs or replacement.

HOW TO CHOOSE BETWEEN GAS LIFT AND PUMPING



COMPARE RATE, RESERVOIR AND COST CONDITIONS

PUMPING

Preferred for:
- An onshore well with low workover costs
- Wells that produce clean fluids
- Low GLR (Gas-Liquid Ratio)
- Submersible pumps
- Beam or hydraulic pumps
- Progressive cavity pumps

HOW TO CHOOSE BETWEEN GAS LIFT AND PUMPING

Preferred for:
- An offshore well with high workover costs
- Wells that produce with high workover costs
- High production rate, reservoir productivity and pressure
- High GLR (Gas-Liquid Ratio)

GAS LIFT

Gas lift and pumping are both efficient techniques under the right circumstances. To decide on a technique, you need to know the purpose and uses of each. To summarize, gas lift is an extension of natural flow and pumping is a technique that uses energy down-hole to raise fluid pressure. Choose the best technique for the project based on rate, reservoir and cost conditions.

Selection of an Artificial Lift System

To realize the maximum potential from developing any oil or gas field, the most economical artificial lift method must be selected. The methods historically used to select the lift method for a particular field vary broadly across the industry.

The methods include

I. Operator experience, II. What methods are available for installations in certain areas of the world, III. What is working in adjoining or similar fields, IV. Determining what methods will lift at the desired rates and from the required depths,
V. Evaluating lists of advantages and disadvantages, VI. "Expert" systems to both eliminate and select systems, VII. Evaluation of initial costs, operating costs, production capabilities, etc.
with the use of economics as a tool of selection, usually on a present value basis Each method has applications for which it is the optimum installation. Proper selection of an artificial lift method for a given production system (reservoir and fluid properties, wellbore configuration, and surface facility restraints) requires a thorough understanding of the system. Artificial lift methods should be designed before completion in order to minimize additional costs due to future workovers and recompletions but this is often not the case.

Conclusion:

I thank God Almighty for giving me the opportunity to participate in this OGIC2 competition. I also thank the organizers of this conference and article competition. Long live Cairo University.

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